Digital Relay Based Adaptive Protection for Distributed Systems with Distributed Generation

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***Abstract*-An adaptive protection scheme using digital relays with a communication network is proposed for the protection of the distributed systems. The impact of distributed generators on protection coordination is first discussed. Then, an adaptive protection scheme is proposed for distributed systems with distributed generation (DG). Simulated results of a total of 256 cases show that the proposed approach can perform adaptive primary and backup protection functions under both balanced and unbalanced fault conditions. Also, the proposed approach is adaptive to the fault types as well as capacities of DG. Compared with the traditional current protection scheme, the primary and backup protection regions have been extended considerably.**

Keywords-Distributed generation (DG); Adaptive protection; Distribution communication; Distributed systems

I. INTRODUCTION

Deregulation and growth of competitive supply markets have recently increased the interest in distributed generation (DG) from renewable and traditional (but highly efficient) sources. The growing concern on climate changes and the always-present oil crisis also multiplies this interest. Furthermore, costs of DG technologies are falling, but the cost of transmission and distribution is rising. To meet an increase of load, it is more economical by interconnecting DG to distribution feeders than expanding transmission and distribution facilities [1]. Studies have predicted that a presence of approximately 20% on energy sources for the years 2010 to 2020 [2] which means DG would feed loads around its location and the assumption of the distribution system being radial is not likely to hold in the near future. One would then be looking at a multisource system.

For a multisource system, protection devices are necessary to be directional sensitive [9-11]. In addition, connecting a generator to a distribution network has the effect of increasing the fault current. Hadjsaid et al. [3] shows through a simple example that fault currents through protective devices would change after introduction of DG. Thus, new fault current and setting should be calculated for the protection coordination preparation. However, the protection coordination under the changing system condition (DG's capacity) is a time-consuming and a tedious task. Thus, disconnection of all DGs from distribution systems is the current local distribution companies' practice during fault in order to maintain the original relay coordination. But throwing off all DGs from system every time a temporary fault occurs would make the system very unreliable. To overcome disconnecting all downstream DGs, An adaptive protection scheme was presented in [4], which depends on remote communication capabilities.

Communication is a major activity in an adaptive relaying system. However, traditional protection relay coordination relies on standalone units that use local measurements and settings as the basis for the decision making. Communication plays a very limited role in these legacy systems. A new era of decentralized control and efficiency demands has led to an environment demanding efficiency and reliability that pushes these legacy methods to their limits.

In this paper, the impact of DG on protection coordination is first analyzed. Then a comprehensive adaptive protection scheme is proposed for distribution systems with a few larger DGs that would undermine the system reliability. In the proposed scheme, communication will play an important role to provide more information for the relay coordination besides the relay settings. The validity and effectiveness of the proposed scheme have been demonstrated by a practical distributed system.

II. IMPACT OF DG ON PROTECTION COORDINATION

In spite of the positive impacts of DGs on system design and operation [3], they change the original steady-state and fault current directions and values. The severity of these changes is based on the DG's location, capacity and number in distribution systems. As it is pointed out in [5], the fault contribution from a single small DG unit may not be large; however, the aggregate contributions of a few larger units, can alter the short-circuit levels enough to cause protective devices to malfunction.

A power network shown in fig.1 is fed through a source G and protected by relays R1, R2 and R3. Each protective device is assigned a primary function to clear faults in a specific zone and a secondary function to clear faults in the adjacent or downstream zones to the extent within the range of the device

permits. In this situation, the next upstream device or device combination must operate to provide backup protection. When two devices operate properly in this primary/secondary mode for any system fault, they are said to be coordinated. Proper coordination is achieved by this discrimination between successive devices. Good practice dictates that when a fault F1 occurs, the time of operation of relay R2 should be made larger than the time of operation of R1 at least by a time interval called the "coordination time interval". As clearly shown in fig.1, R2 will back up R1.

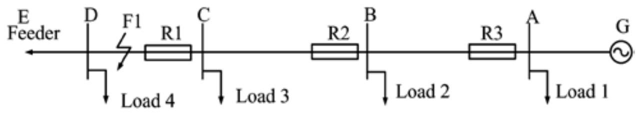

Fig.1. A power network fed through source G and protected by relays R1, R2 and R3.

It is clear that protection for distribution systems with DG cannot be achieved with the same philosophies that have been used to protect traditional distribution systems. At the very least, a system designed to protect distribution systems with DG should take the following into consideration

A. Bidirectional Current Flow

If DG1 and DG2 connect to the system as shown in figure 2, R1 and R2 will see the same current for fault F1 (downstream) or fault F2 (upstream). For F2, selectivity requires that R2 operates before R1 and for F1, R1 should operate before R2. Since these relays sense the same current for either of these faults, it is impossible to achieve coordination with the existing scheme. This means that the system should be facilitated with two directional protection devices at each line to ensure the correct fault isolation, as shown in figure 3.

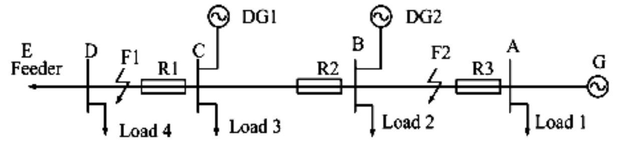

Fig. 2. A power network fed through source G, DG1 and DG2, and protected by relays R1, R2, R3.

B. Changing System Conditions

For F1, The fault current now has two components-one coming from the supply, and the other from DG1 and DG2. Under the condition of changing of capacities of DGs, the maximum and minimum fault currents will change. This will require R1 and R2 to be coordinated at changing current conditions.

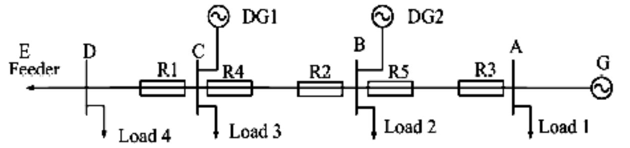

Fig.3. An industrial power network with directional protection devices to ensure the correct fault isolation.

Reference [6] analyzes part of an actual distribution system to identify some more potential cases of mal-coordination that depend on size and placement of DG in system. It concludes that, in general, if protection scheme is not changed, the only way to maintain coordination in presence of arbitrary DG penetration is to disconnect all DG instantaneously in case of fault. This would enable the system to regain its radial nature and coordination would withhold. But this would mean that DG is disconnected even for temporary faults.

III. ADAPTIVE PROTECTION SCHEME

A. Communication Coordination

To avoid throwing off all DGs from system every time, the relays should respond to the changing system conditions and adapt according to the new prevailing conditions. In adaptive coordination, communication is a major activity in an adaptive relaying system. Considering the operating cost and the connection speed, wire- or fiber-based systems are viable alternatives for communication of data in adaptive schemes [7]. The costs can be further controlled by not using specific communication channels, but by existing connections already deployed in that part of the system. For instance, if 'smart grid' technologies have already been deployed, the corresponding communication channel can be used. In this situation, the relay at the bus with a communication link to the adjacent or downstream measurements of the current and switching device status is able to perform adequately for faults encountered in distribution systems and enable cost-effective protection schemes.

B. Adaptive Primary Protection Setting for Feeders with DGs

For traditional distribution systems, the substation is the only source of power. In addition, due to the substations away from large generation units, the initial high "sub-transient component" does not exist in the fault current transients. Therefore, the fault current can be approximated by its steady-state value. In this way, the feeder can be represented by a steady-state model, in which the substation is represented as a voltage source behind a Thevenin's impedance. If there are conventional DGs on the feeder, the above feeder model can be obtained easily by employing the simple Thevenin's equivalent models for these generators [8].

However, for other kinds of DGs that responds considerably after a fault occurs, the same technique cannot be applied [12]-[17]. Therefore, a new scheme is needed to incorporate all DGs into the fault analysis.

As shown in figure 3, DG1 can be represented as an injected current i1 the lines CD and DE are represented by their series impedance ZCE, and the Load 3 can be represented by its equivalent impedances Zd3. The corresponding equivalent circuit of these devices can then be represented by Norton equivalent model as shown in figure 4, which can then be easily transformed to Thevenin's equivalent model as shown in figure 5. The voltage u1 behind the Thevenin's impedance is calculated as

$$u_1 = i_1 \frac{Z_{CE}.z_{d3}}{Z_{CE} + z_{d3}} \tag{1}$$

Thus, the adaptive primary protection setting for R4 can be formulated as

$$i_{ps4} = \frac{k_k k_d u_1}{Z_m + z_l} \tag{2}$$

$$Z_m = \frac{Z_{CE} . z_{d3}}{Z_{CE} + z_{d3}} \tag{3}$$

Where i_{ps4} is the adaptive primary protection setting for R4. Zm is the integrated impedance of source side. z_l is the protected line impedance. kd is the coefficient of fault type and can be previously determined by software used by utilities. kk is the coefficient of reliability. A similar procedure can also be applied to R5 for its adaptive primary protection setting ips5.

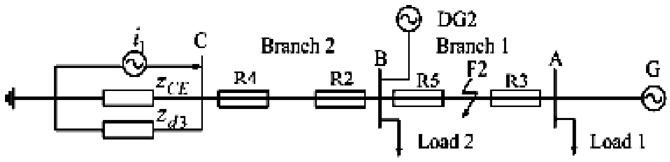

Fig. 4. Norton equivalent model behind R4

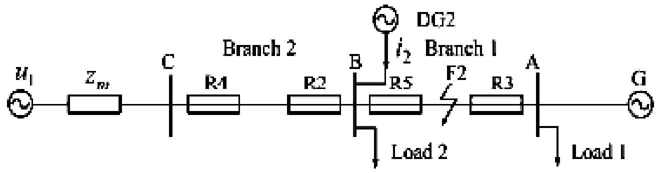

Fig.5. Thevenin's equivalent model behind R4.

C. Adaptive Backup Protection Setting for Feeders with DGs

In the event of a switching device failure, the next upstream device, or device combination, must operate to provide backup protection. A typical case is shown in figure 5. For F2, if the measured current of R5 is still above the threshold after a certain time delay, measurements of the current (including the injected current of DG2, i2) and switching device status at bus B will be sent to R4 to provide backup protection. However, since DG2 may response considerably after a fault occurs, measured currents of R4 and R5 will change dramatically. Therefore, it is recommended to eliminate the effect of DG2 on these measurements.

The nodal equations of the distribution systems can be written as

$$I_N = Y_N U_N \tag{4}$$

$$Y_N = AYA^T \tag{5}$$

Where YN is the node admittance matrix. UN is the voltage at each node. IN is the current injected at each node. A is the node correlation matrix. Y is the branch admittance matrix.

The branch current can be obtained by multiplying voltage difference between two ends of a branch with that branch admittance. Therefore, the relationship between the branch current IB and the node voltage UN can be expressed as

$$I_B = YA^T U_N \tag{6}$$

From (4)-(6), the relationship between the branch current IB and the injected current IN can be deduced as

$$I_B = YA^T Y_N^{-1} I_N \tag{7}$$

Where $c(\lambda) = YA^T Y_N^{-1}$ is defined as the system correlation coefficient matrix.

The current of the kth branch caused by the injected current of DG2 is calculated as

$$i_{k,B} = \lambda_{k2} i_2 \tag{8}$$

Where ik,B is the current of kth branch caused by the injected current of DG2.

λ_{k2} is the element of the system correlation coefficient matrix $c(\lambda)$. The impact of DG2 on the current of kth branch can be eliminated by

$$i_{k,d} = i_{k,m} - i_{k,B} \tag{9}$$

where ik,m is the measured current of kth branch. ik,d is the current of kth branch without the impact of DG2.

Similar procedure is then applied to the branches connected with R4 and R5. In this situation, the adaptive backup protection setting can be formulated as

$$i_{bs4} = k_k^{'} i_{ps5} / k_b \tag{10}$$

$$k_b = i_{1,d} / i_{2,d} \tag{11}$$

where ibs4 is the adaptive backup protection setting for R4. ips5 is the primary protection setting for R5. kb is the branch coefficient. $k_k^{'}$. is the coefficient of reliability. $i_{1,d}$ is the current of branch 1 and $i_{2,d}$ is the current of branch 2 both are without the impact of DG2.

IV. TEST SYSTEM AND RESULTS

A. Test Systems

To test the performance of the proposed adaptive protection method, a practical 10KV distributed system of power network is used in this study as shown in figure 6.

The base capacity is 500MVA and the base voltage is 10.5KV. Branches AB, BC and AF are all overhead lines. The parameters of these lines are: r1=0.27Ω/km, x1=0.347Ω /km. Branches CD, DE and FG are all underground cables. The parameters of these lines are: r1=0.259Ω/km, x1=0.093Ω/km.

Each load has the nominal capacity 6MVA and nominal power factor 0.85. DG1 and DG2 with P-Q control schemes are connected to bus C and bus E, respectively. Their nominal capacities are both 10MVA. Additionally, any lines that will experience bidirectional current flow will need two protection devices at each line, whereas any lines that will not experience bidirectional current flow will only need one protection device instead of two, thus reducing the cost.

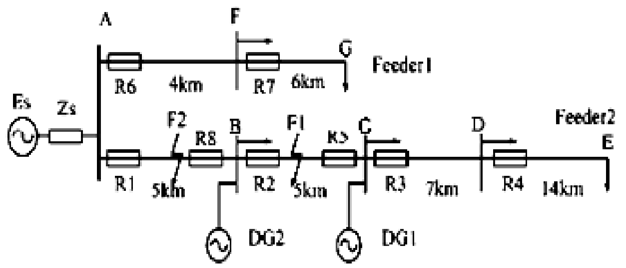

Fig. 6. A 10KV distribution system of power network

The test system is simulated by using PSCAD/EMTDC. A total of 256 cases have been tested with different locations, different fault types (balanced and unbalanced), and different capacities of DG1. In the following analysis, Ips5 and Ipm5 represent the adaptive primary protection setting and the measured current of R5 respectively. Ibs5 and Ibm5 represent the adaptive backup protection setting and the measured current of R5 without the impact of DG2, respectively.

B. Responses of Adaptive Primary Protection Scheme

For conventional source in the distribution systems, the fault current can be approximated by its steady-state value. But for DGs that response considerably after a fault occurs, the same technique cannot be applied. Therefore, the proposed adaptive protection scheme mainly focuses on lines fed through DGs. A typical case is shown in figure 6. A three-phase fault was applied to the middle of the line between buses B and C at 0.30 seconds. The fault is cleared after 0.5 seconds.

When the fault occurs, the fault current flowing through R5 is fed by DG1. Thevenin's equivalent model behind R5 can be obtained by using (1) and (3), and Ips5 can be calculated by using (2).

Figure 7 shows the curves of Ips5 and Ipm5. It can be found that after the fault occurs, Ipm5 responds considerably and becomes larger than Ips5. Thus, the primary protection issues a signal to the switching device to trip the fault.

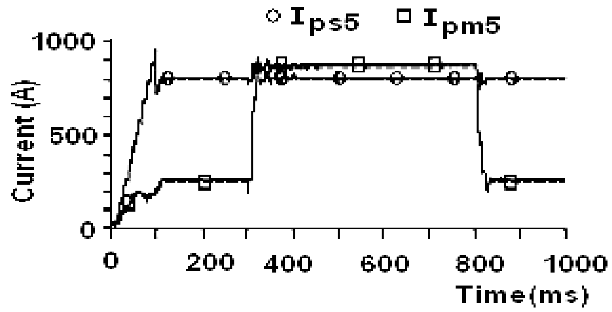

Fig.7.The adaptive primary protection setting and the measured current of R5 when a three-phase fault occurs in the middle of Section BC.

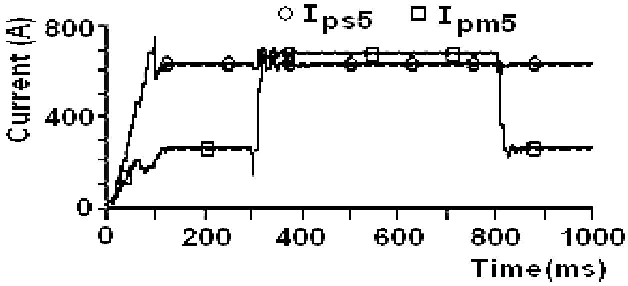

Fig.8. The adaptive primary protection setting and the measured current of R5 when a phase-to-phase fault occurs in the middle of Section BC.

Additionally, a case of phase-to-phase fault was simulated in the middle of Section BC at 0.3 seconds and was cleared after 0.5 seconds. Ipm5 and Ips5 are shown in Figure 8. It can be seen that Ipm5 is larger than Ips5 after fault occurs, which makes the relay tripping the fault accurately.

TABLE -1SIMULATION RESULTS OF PHASE-TO-PHASE AND THREE PHASE FAULTS IN CASE OF ADAPTIVE PRIMARY PROTECTION

MVA	α	L-L Fault		L-L-L Fault	
		$I_{ps,5}$ (KA)	$I_{pm,5}$ (KA)	$I_{ps,5}$ (KA)	$I_{pm,5}$(KA)
10	0.5	0.628	0.675	0.823	0.845
	0.7	0.623	0.636	0.814	0.833
	0.8	0.621	0.629	0.806	0.827
5	0.5	0.176	0.185	0.235	0.248
	0.7	0.175	0.178	0.226	0.236
	0.8	0.173	0.175	0.220	0.224
1	0.5	0.0209	0.0213	0.054	0.068
	0.7	0.0204	0.0212	0.049	0.055
	0.8	0.0196	0.0210	0.044	0.049

C. Responses of Adaptive Backup Protection Scheme

If a fault occurs on Section AB close to bus B, and the measured current of R8 is still above the threshold after a certain time delay, then R5 must operate to provide adaptive backup protection. In this situation, the impact of DG2 on the branch currents is first eliminated by using (4)-(9). Then, Ibs5 is calculated by using (10) and (11).

Figure 9 shows Ibs5 and Ibm5 in case of a three-phase fault, whereas figure 10 shows Ibs5 and Ibm5 in case of a phase-to-phase fault. It can be found that no matter what types of faults occur, Ibm5 is greater than Ibs5 in both figures. Thus, in each case, the adaptive backup protection at R5 will issue a signal to the switching device to clear the fault on the adjacent Section AB.

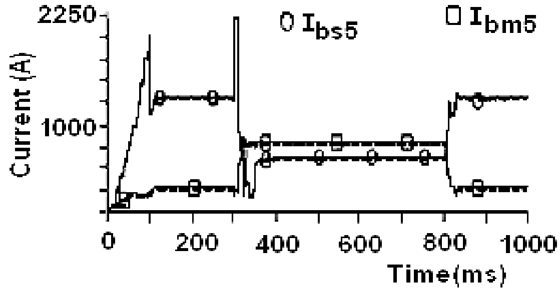

Fig.9. The adaptive backup protection setting and the measured current of R5 when a three-phase fault occurs on Section AB close to bus B.

TABLE -2SIMULATION RESULTS OF PHASE-TO-PHASE AND THREE-PHASE FAULTS IN CASE OF ADAPTIVE BACKUP PROTECTION

MVA	α	L-L Fault		L-L-L Fault	
		Ips,5 (KA)	*Ipm,5(KA)*	*Ips,5(KA)*	*Ipm,5 (KA)*
10	1.0	0.455	0.587	0.619	0.763
	1.2	0.383	0.568	0.609	0.729
	1.4	0.367	0.533	0.582	0.700
5	1.0	0.162	0.168	0.171	0.210
	1.2	0.143	0.163	0.165	0.187
	1.4	0.132	0.159	0.158	0.172
1	1.0	0.0106	0.0164	0.034	0.042
	1.2	0.0098	0.0145	0.033	0.040
	1.4	0.0087	0.0122	0.032	0.038

D. Comprehensive Fault Analysis

A comprehensive fault analysis is performed for different locations, different fault types (balanced and unbalanced), and different capacities of DG1. Table 1 shows Ips5 as long as Ipm5 under various conditions. The distance between the fault location and R5 is defined as fault distance. α is the ratio between the fault distance and the length of protected line BC. It can be concluded that the extent of the adaptive primary protection is more than 80% of the protected line BC. But the extent of the traditional current primary protection is less than 20% of the protected line.

In the event of a switching device close to R8 failure, the next upstream device R5 must operate to provide backup protection. The measured currents of R5 as long as Ibs5 under various conditions are shown in Table 2. It can be founded that not only the whole protected line BC but also part of the adjacent line can be protected. The extent of the adaptive backup protection is more than 140% of the line BC, whereas the extent of the traditional current backup protection is less than 80% of the protected line.

R5 has achieved both a primary function to clear faults in a specific zone and a secondary function to clear faults in the adjacent zone to the extent considerably larger than that calculated by traditional method. Furthermore, the proposed scheme is not affected by the fault types and capacities of DG1. Thus, the protection performance has been greatly improved.

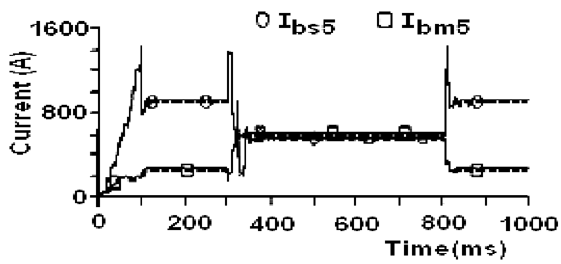

Fig.10. The adaptive backup protection setting and the measured current of R5 when a phase-to-phase fault occurs on Section AB close to bus B.

V. CONCLUSION

One problem with distributed generation (DG) implementation is designing a proper protection scheme. After connecting DG, part of the system may no longer be radial, which means the traditional protection schemes might not work successfully. The adaptive scheme proposed here offers a practically acceptable solution to this problem in the distribution system. The proposed scheme is adaptive to the fault types as well as capacities of DG. Furthermore, the primary and backup protection regions have been extended considerably compared with the traditional current protection scheme. Simulation results verify that the proposed scheme is able to clear faults under both balanced and unbalanced fault conditions.

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